SECTION 2.0

Project Description

SECTION 2.0

Project Description

2.1 Introduction

The following sections describe the design and operation of the proposed project, associated electric transmission lines, natural gas supply line, and water lines. Site selection and alternative sites considered are presented in Section 9.0.

Section 2.1 is the introduction, which provides a brief overview of the project. Section 2.2 contains a description of the generating facility, its design, and its proposed operation. Section 2.3 discusses the safety design of the facility. Section 2.4 discusses the expected facility reliability. Section 2.5 refers to the laws, ordinances, regulations, and standards (LORS) applicable to each engineering discipline.

The Central Valley Energy Center (CVEC) will be a nominal 1,060-megawatt (MW) net combined-cycle generating facility configured using three natural-gas-fired turbines and one steam turbine. CVEC will connect to Pacific Gas and Electric's (PG&E) electrical transmission system via PG&E's Panoche – McCall and Panoche – Kearney 230-kV transmission lines, which are located on a parcel to the south of the project site. Natural gas for the facility will be delivered via approximately 20 miles of new 24-inch pipeline that will connect to PG&E's existing gas transmission lines (Line 2 and Line 401) located 20 miles west of the project site. Approximately 7,000 acre-feet per year (afy) of reclaimed water for cooling tower and process makeup water will be supplied by Fresno-Clovis Wastewater Treatment Facility (WWTF) via a 21-mile pipeline. Domestic water for drinking and sanitary uses would be provided from the City of San Joaquin municipal system. Similarly, domestic wastewater disposal will be to the City of San Joaquin sewer system.

Cooling water will be cycled in the cooling tower three to eight times (depending on water quality). The blowdown will be concentrated and the water reclaimed onsite using a zero-liquid discharge (ZLD) system (see Section 2.2.9.1.2).

CVEC will be located on approximately 85 acres of land under the Applicant's control. The site is located in an industrial area of the City of San Joaquin, Fresno County. Figure 2.1-1 (all figures are located at the end of this section) shows the location of the generating facility site, electric transmission line, natural gas supply line, reclaimed water supply line, domestic water supply line and wastewater disposal line. The legal description of the project site is provided in Appendix 1A. Property owners within 1000 feet of the CVEC boundaries, and within 500 feet of project transmission lines, gas lines, and water lines are provided in Appendix 1B.

2.2 Generating Facility Description, Design, and Operation

This section describes the facility's conceptual design and proposed operation.

2.2.1 Site Arrangement and Layout

The site plan on Figure 2.2-1 and typical elevation views on Figure 2.2-2 illustrate the location and size of the proposed generating facility. Settled areas, parks, and recreational and scenic areas near the site and the proposed transmission lines are shown in Figure 2.2-3.

The site is located adjacent and to the west of the intersection of W. Colorado Avenue and Springfield Avenue. Access to the site will be provided via a new road built off Colusa Avenue on the west side of the parcel. This new road was anticipated in development plans of the City and would be an extension of Cherry Lane (see Figure 2.1-1). Most of the power block will be paved to provide internal access to all project facilities and onsite buildings. The areas around equipment, where not paved, will have gravel surfacing. An existing 70-kV subtransmission line bisecting the site will be rerouted to the eastern property boundary (see Figure 2.1-1). The proposed 230-kV transmission line interconnect from the project site, 1500 feet south to PG&E's existing transmission lines, is shown in Figure 2.1-1. The single-line representation of the interconnect is depicted in Figure 2.2.4.

2.2.2 Process Description

The generating facility will consist of three combustion turbine generators (CTGs) equipped with dry, low oxides of nitrogen (NO_x) combustors and steam injection power augmentation capability; three heat recovery steam generators (HRSG) with duct burners; one condensing steam turbine generator (STG); a deaerating surface condenser; 16-cell mechanical-draft cooling tower; and associated support equipment providing a total net generating capacity of 1,060 MW. The combustion turbines are expected to be Siemens-Westinghouse 501FD units. One nominal 125,000-pound-per-hour auxiliary boiler will also be included to provide steam as needed for auxiliary purposes.

Each CTG will generate approximately 180 MW at base load under average ambient conditions. The CTG exhaust gases will be used to generate steam in the HRSGs. The HRSGs will use reheat design with duct firing. Steam from the HRSGs will be admitted to a condensing steam turbine generator. Approximately 550 MW will be produced by the steam turbine when the CTGs are operating at base load at average ambient conditions with maximum duct firing within the HRSGs. The project is expected to have an overall annual availability of 92 to 98 percent.

The generating facility base load operation heat balance is shown on Figure 2.2-5. This balance is based on an ambient dry bulb temperature of 61°F (annual average) with fogging of the combustion air, no steam injection for power augmentation, and no duct firing.

Associated equipment will include emission control systems necessary to meet the proposed emission limits. NO_x emissions will be controlled to 2.0 parts per million by volume, dry basis (ppmvd) corrected to 15 percent oxygen (@ 15 percent O_2) on an annual average basis (2.5 ppmvd on a short-term basis) by a combination of low NO_x combustors in the CTGs and selective catalytic reduction (SCR) systems in the HRSGs. A carbon monoxide (CO) catalyst will be installed in the HRSGs to limit CO emissions from the CTGs to 6 ppmvd @ 15 percent O_2. The auxiliary boiler will be limited to 9 ppmvd NO_x at 3 percent oxygen and 50 ppmvd CO at 3 percent oxygen.

2.2.3 Generating Facility Cycle

CTG combustion air flows through the inlet air filter and fogging section and associated air inlet ductwork, is compressed in the gas turbine compressor section, and then flows to the CTG combustor. Natural gas fuel is injected into the compressed air in the combustor and ignited. The hot combustion gases expand through the power turbine sections of the CTGs, causing them to rotate and drive the electric generators and CTG compressors. The hot combustion gases exit the turbine sections at approximately 1,150 degrees Fahrenheit (°F) and enter the HRSGs. In the HRSGs, boiler feedwater is converted to superheated steam and delivered to the steam turbine at three pressures: high-pressure (HP), intermediate-pressure (IP), and low-pressure (LP). The use of multiple steam delivery pressures increases cycle efficiency and flexibility. High-pressure steam expands through the HP section of the steam turbine. This expanded steam, referred to as cold reheat steam, is combined with the IP steam and returned to the reheater section of the HRSGs. This mixed, reheated steam (called “hot reheat”) is then expanded in the IP steam turbine section. Steam exiting the IP section of the steam turbine is mixed with LP steam and expanded in the LP steam turbine section. Steam leaving the LP section of the steam turbine enters the surface condenser where it is condensed. The heat energy of the condensing steam transfers to a circulating water loop, which, in turn, exhausts heat to the atmosphere by means of a mechanical draft cooling tower.

2.2.4 Combustion Turbine Generators, Heat Recovery Steam Generators, Steam Turbine Generator and Condenser, and Auxiliary Boiler

Electricity is produced by the three CTGs and the STG. The system also contains an auxiliary boiler. The following paragraphs describe the major components of the generating facility.

2.2.4.1 Combustion Turbine Generators

Thermal energy is produced in the CTGs through the combustion of natural gas, which is converted into mechanical energy required to drive the combustion turbine compressors and electric generators. Three “F” class CTGs have been selected for CVEC; these CTGs will be supplied by Siemens-Westinghouse.

Each CTG system consists of a stationary combustion turbine generator, supporting systems, and associated auxiliary equipment. The CTGs will have power augmentation capability by use of steam injection upstream of the power turbine section.

The CTGs will be equipped with the following required accessories to provide safe and reliable operation:

- Inlet air foggers
- Inlet air filters
- Metal acoustical enclosure
- Double lube oil cooler
- Dry low NO_x combustion system
- Compressor wash system
- Fire detection and protection system
- Fuel heating system

The metal acoustical enclosure, which contains the CTGs and accessory equipment, will be located outdoors.

2.2.4.2 Heat Recovery Steam Generators

The HRSGs provide for the transfer of heat from the exhaust gases of the CTGs to the feedwater, which is turned into steam. The HRSGs will be three-pressure, natural circulation units equipped with inlet and outlet ductwork, duct burners, insulation, lagging, and separate exhaust stacks.

Major components of each HRSG include an LP economizer, LP drum, LP evaporator, LP superheater, IP economizer, IP evaporator, IP drum, IP superheaters/reheaters, HP economizers, HP evaporator, HP drum, and HP superheaters. The LP economizer receives condensate from the condenser hot well via the condensate pumps. The LP economizer is the final heat transfer section to receive heat from the combustion gases prior to their exhausting to the atmosphere.

From the LP economizer, the condensate is directed to the LP drum where it is available to generate LP steam and supply condensate to the boiler feed pumps. The boiler feed pumps draw suction from the LP drum and provide additional pressure to serve the separate IP and HP sections of the HRSG.

Feedwater from the boiler feed pumps is sent to the HP section of the HRSG. High-pressure feedwater flows through the HP economizer where it is preheated prior to entering the HP steam drum. Within the HP steam drum, a saturated liquid state will be maintained. The saturated water will flow through downcomers from the HP steam drum to the inlet headers at the bottom of the HP evaporator. Saturated steam will form in the tubes as energy from the combustion turbine exhaust gas is absorbed. The HP-saturated liquid/vapor mixture will then return to the steam drum where the two phases will be separated by the steam separators in the drum. The saturated water will return to the HP evaporator, while the vapor continues on to the HP superheater. Within the HP superheater, the temperature of the HP steam will be increased above its saturation temperature, or “superheated” prior to being admitted to the HP section of the steam turbine.

Feedwater will also be sent to the IP section of the HRSG by an interstage bleed from the boiler feed pumps. Similar to the HP section, feedwater will be preheated in the IP economizer and steam will be generated in the IP evaporator. The saturated IP steam will pass through an IP superheater and then be mixed with “cold reheat” steam from the discharge of the steam turbine HP section. The blended steam will then pass through two additional IP superheaters reheating the steam to a superheated state. The “hot reheat” steam will then be admitted to the steam turbine IP section.

Condensate will be preheated by the LP economizer prior to entering the LP steam drum. Similar to the HP and IP sections, steam will be generated in the LP evaporator and superheated in the LP superheater. The superheated LP steam will then be admitted to the LP section of the steam turbine along with the steam exhausting from the steam turbine IP section.

Duct burners will be installed in the HRSGs. These burners will provide the capability to increase steam generation and provide greater operating flexibility and improved steam temperature control. The duct burners will burn natural gas. The duct burner for each HRSG will be sized for a heat output of up to 746 million British thermal units (MMBtus) per hour on a higher heating value (HHV) basis.

The HRSG will be equipped with an SCR emission control system that will use ammonia vapor in the presence of a catalyst to reduce NO_x in the exhaust gases. The catalyst module will be located within the HRSG casing. Diluted ammonia (NH_3) vapor will be injected into the exhaust gas stream via a grid of nozzles located upstream of the catalyst module. The subsequent chemical reaction will reduce NO_x to nitrogen and water, resulting in an NO_x concentration in the HRSG exhaust gas no greater than 2.0 ppmvd at 15 percent oxygen (on an average annual basis).

An oxidation catalytic converter will also be installed within the HRSG casing to control the concentration of CO in the exhaust gas emitted to atmosphere to no greater than 6 ppmvd at 15 percent oxygen. Exhaust from each HRSG will be discharged from individual 145-foot-tall, 20-foot diameter exhaust stacks.

2.2.4.3 Steam Turbine Generator

The steam turbine system consists of a condensing steam turbine generator (STG) with reheat, gland steam system, lubricating oil system, hydraulic control system, and steam admission/induction valving.

Steam from the HRSG HP, IP, and LP superheaters enters the associated steam turbine sections through the inlet steam system. The steam expands through multiple stages of the turbine, driving the generator. On exiting the turbine, the steam is directed into the surface condenser.

2.2.4.4 Auxiliary Boiler

An auxiliary boiler, capable of providing up to 125,000 pounds per hour (lb/hr) of saturated steam at 400 pounds per square inch gauge (psig), will be provided for HRSG HP steam drum sparging, condenser hotwell sparging, steam turbine gland steam, and deaeration steam when the plant is offline. For prolonged outages, a nitrogen blanket will be used to lay-up the HRSG to alleviate the need to run the auxiliary boiler (decrease in fuel use and emissions). An electric superheater will be provided for the steam turbine gland steam. The auxiliary boiler will be a forced-draft unit served by a feedwater deaerator and boiler feedwater pump system. It will be equipped with an economizer to maximize fuel efficiency.

The auxiliary boiler will be equipped with a low-NO_x combustor and if required, an SCR system and CO catalyst to control NO_x and CO concentrations in the exhaust gas. The auxiliary boiler will exhaust through a free-standing 120-foot-tall, 3½-foot diameter steel stack.

2.2.5 Major Electrical Equipment and Systems

The bulk of the electric power produced by the facility will be transmitted to the PG&E grid. A small amount of electric power will be used onsite to power auxiliaries such as pumps and fans, control systems, and general facility loads including lighting, heating, and air conditioning. Some will also be converted from alternating current (AC) to direct current (DC), which is used as backup power for control systems and other uses. Transmission and auxiliary uses are discussed in the following subsections. Figure 2.2-3 illustrates the settled areas, scenic areas, and existing transmission lines within one mile of the proposed transmission line routes.

2.2.5.1 AC Power—Transmission

Power will be generated by the three CTGs at 15-kV and one STG at 18-kV and then stepped up by four transformers to 230-kV for transmission to the grid. An overall single-line diagram of the facility's electrical system is shown on Figure 2.2-4. The generator will be connected by an isolated-phase bus to oil-filled step-up transformers that increase the voltage to 230-kV. Surge arresters will be provided at the high-voltage bushings to protect the transformers from surges on the 230-kV system caused by lightning strikes or other system disturbances. The transformers will be set on concrete pads within containments designed to contain the transformer oil in the event of a leak or spill. Fire protection systems will be provided. The high-voltage side of the step-up transformers will be connected via overhead cables to the plant's 230-kV switchyard. From the switchyard, power will be transmitted via transmission lines owned by PG&E.

The CVEC facility will be connected to PG&E's transmission system by looping both the Panoche – McCall and Panoche – Kearney lines into the CVEC switchyard. This will be accomplished by intercepting both 230-kV transmission lines immediately south of the site and installing two double-circuit pole lines into the CVEC switchyard. A detailed discussion of the transmission system is provided in Section 5.0.

2.2.5.2 AC Power—Distribution to Auxiliaries

Auxiliary power to the combustion turbine and steam turbine power block will be supplied at 4,160 volts AC by a double-ended 4,160-volt switchgear lineup. Primary power to the switchgear will be supplied by two oil-filled, 15-kV to 4.16-kV unit auxiliary/station service stepdown transformers. The high-voltage side (15-kV) of the unit auxiliary/ station service transformers will be connected to the outputs of two of the three CTGs. This connection will allow the switchgear to be powered from either or both of the two CTGs or by back-feeding power from the 230-kV switchyard. Low-voltage side (15-kV) generator circuit breakers will be provided for the two CTGs capable of feeding power to the 4,160-volt switchgear. These circuit breakers, used to isolate and synchronize the generators, will be located between the generators and the connections to the unit auxiliary/station service transformers. A 1,040-kW natural-gas-fired emergency generator will be provided to supply power to emergency loads and auxiliary boiler loads when power is not available through the 230-kV interconnection to the grid.

The 4,160-volt switchgear lineup supplies power to the various 4,160-volt motors, to the combustion turbine starting system, and to the load center (LC) transformers, rated 4,160 to 480 volts, for 480-volt power distribution. The switchgear will have vacuum interrupter circuit breakers for the main incoming feeds and for power distribution.

The LC transformers will be oil-filled, each supplying 480-volt, 3-phase power to the double-ended load centers.

The load centers will provide power through feeder breakers to the various 480-volt motor control centers (MCCs). The MCCs will distribute power to 480-volt motors, to 480-volt power distribution panels, and lower voltage lighting and distribution panel transformers. Power for the AC power supply (120-volt/208-volt) system will be provided by the 480-volt MCCs and 480-volt power panels. Transformation of 480-volt power to 120/208-volt power will be provided by 480-120/208-volt dry-type transformers.

2.2.5.3 125-volt DC Power Supply System

One common 125-volt DC power supply system consisting of one 100 percent capacity battery bank, two 100 percent static battery chargers, a switchboard, and 2 or more distribution panels will be supplied for balance-of-plant and STG equipment. Each CTG and the switchyard protection relay panel will be provided with their own separate battery systems and redundant chargers.

Under normal operating conditions, the battery chargers supply DC power to the DC loads. The battery chargers receive 480-volt, three-phase AC power from the AC power supply (480-volt) system and continuously charge the battery banks while supplying power to the DC loads.

Under abnormal or emergency conditions when power from the AC power supply (480-volt) system is unavailable, the batteries supply DC power to the DC system loads. Recharging of a discharged battery occurs whenever 480-volt power becomes available from the AC power supply (480-volt) system. The rate of charge depends on the characteristics of the battery, battery charger, and the connected DC load during charging. The anticipated maximum recharge time will be 12 hours.

The 125-volt DC system will also be used to provide control power to the 4,160-volt switchgear, to the 480-volt LCs, to critical control circuits, and to the emergency DC motors.

2.2.5.4 Uninterruptible Power Supply System

The combustion turbines and steam turbine power block will also have an essential service 120-volt AC, single-phase, 60-hertz (Hz) uninterruptible power supply (UPS) to supply AC power to essential instrumentation, to critical equipment loads, and to unit protection and safety systems that require uninterruptible AC power.

Redundant UPS inverters will supply 120-volt AC single-phase power to the UPS panel boards that supply critical AC loads. The UPS inverters will be fed from the station 125-volt DC power supply system. Each UPS system will consist of one full-capacity inverter, a static transfer switch, a manual bypass switch, an alternate source transformer, and two or more panelboards.

The normal source of power to the system will be from the 125-volt DC power supply system through the inverter to the panelboard. A solid-state static transfer switch will continuously monitor both the inverter output and the alternate AC source. The transfer switch will automatically transfer essential AC loads without interruption from the inverter output to the alternate source upon loss of the inverter output.

A manual bypass switch will also be included to enable isolation of the inverter for testing and maintenance without interruption to the essential service AC loads.

The Distributed Control System (DCS) operator stations will be supplied from the UPS. The continuous emission monitoring (CEM) equipment, DCS controllers, and input/output (I/O) modules will be fed using either UPS or 125-volt DC power directly.

2.2.6 Fuel System

The CTGs, HRSG duct burners, and auxiliary boiler will be designed to burn natural gas. Natural gas requirements during base load operation are approximately 5,600 MMBtu/hr (HHV basis). Maximum natural gas requirements during peak load operation are approximately 7,900 MMBtu/hr (HHV basis).

Natural gas will be delivered to the site via pipeline (see Section 6.0). The natural gas will flow through gas scrubber/filtering equipment, a gas pressure control station, a fuel gas heater, and a flow-metering station prior to entering the combustion turbines. Low-pressure gas for the emergency generator, auxiliary boiler, and HRSG duct burner systems will be provided by a central pressure reduction station and an LP gas distribution system.

Historical data indicates that the pressure on the PG&E Lines 2 and 401 will vary. At times when the pressure at the fenceline drops below 550 psig, an electric motor-driven gas compressor will be used to boost the plant pressure. The compressor will be located within an acoustically treated building.

2.2.7 Water Supply and Use

This section describes the quantity of water required, the source(s) of the water supply, and water treatment requirements. Two water balance diagrams are included, representing two operating conditions. Figures 2.2-6a and 2.2-6b represent: (1) annual average operation at 61°F with 3 CTGs operating at 100 percent load, no HRSG duct firing, CTG inlet air fogging, and no CTG power augmentation steam injection; and (2) peak operation at 100°F with 3 CTGs operating at 100 percent load, maximum HRSG duct firing, CTG inlet air fogging, and CTG power augmentation steam injection. The water source for all water balances is the reclaimed water from Fresno-Clovis WWTF.

Reclaimed water for cooling tower and process makeup water will be provided by Fresno-Clovis WWTF. Water for the proposed project would be produced from six new, dedicated reclamation wells located at the Fresno WWTP effluent disposal ponds. Fresno discharges approximately 76,000 afy to 1,600 acres of disposal ponds. As a result of years of application, the water elevation under these ponds has risen substantially above the groundwater aquifer, forming a mound of impaired water. New “Flowpath” wells installed near the downstream side of the water mound would extract this reclaimed water for distribution to CVEC. To meet California Code of Regulations (CCR) Title 22 requirements, the water would be chlorinated (sodium hypochlorite) before being piped approximately 21 miles to CVEC. At the CVEC site, it would be stored in two 1.5 million-gallon storage tanks. There are specific monitoring and water quality conditions that need to be met, and CVEC and the City of Fresno are working closely with the Department of Health Services and Regional Water Quality Control Board to prepare the necessary permits. Using this water source for the project assists the City of Fresno in its goal to re-use 100 percent of the water sent to the disposal ponds, and to reduce the elevation of the impaired water mound under the disposal ponds. Use of this water makes higher quality water available for other uses such as domestic or in-stream beneficial uses. A more detailed description of the water supply system, treatment and permits is provided in Section 7.0.

During normal operation, distillate from the ZLD treatment system will be used as process makeup to the demineralized water system. During peak operation, distillate from the ZLD treatment system and additional makeup water is needed. Because of water quality requirements, reclaimed water will always be the source for supplemental process makeup water. Domestic water for sinks, showers, toilets, and eye wash/safety showers will be provided by the City of San Joaquin.

2.2.7.1 Water Requirements

A breakdown of the estimated average daily quantity of water required is presented in Table 2.2-1. The daily water requirements shown are estimated quantities based on the combined cycle plant operating at a constant 821 MW, at an ambient temperature of 61°F without duct firing or steam injection. Peak water requirements shown in Table 2.2-1 are based on the plant operating at a constant net output of 1,060 MW at an ambient temperature of 100°F with maximum duct firing and steam injection. The water balances and water requirements for the peak condition reflect the use of CTG power augmentation steam injection on a continuous basis. The plant would be expected to operate with less than 12 hours per day of steam injection.

TABLE 2.2-1
Estimated Average Daily Water Requirements

Ambient Temperature	Source Water	Peak Requirements
61°F	100 percent Fresno-Clovis WWTF Reclaimed Water	5,342 afy (3,321 gpm)
100°F	100 percent Fresno-Clovis WWTF Reclaimed Water	7,000 afy (6,455 gpm)

2.2.7.2 Water Supply

During normal operation, approximately 99 percent of the total water requirements for CVEC are for cooling water that is used to condense steam discharging from the steam turbine. The cooling water is then circulated through the cooling tower to transfer the heat gained from condensing the steam into the atmosphere. During peak operation (maximum HRSG duct firing, CTG inlet air fogging, and CTG power augmentation steam injection), approximately 84 percent of the total water requirements are for cooling water makeup.

The remaining water needed for the plant is for process makeup water for the HRSGs, CTG inlet air fogging, CTG power augmentation steam, drains, plant general service water, and potable water for domestic use. A detailed description of the water supply is presented in Section 7.0.

2.2.7.3 Water Quality

Section 7.0 includes a projection of the reclaimed water quality based on data from the Fresno-Clovis WWTF. Water quality is analyzed in Section 8.14, Water Resources.

2.2.7.4 Water Treatment

Figures 2.2-6a and 2.2-6b illustrate the water treatment and distribution system. Water use can be divided into the following four levels based on the quality required: (1) water for the circulating or cooling water system; (2) service water for the plant, which includes all other miscellaneous uses; (3) demineralized water for makeup to the HRSGs and auxiliary boilers; and (4) potable water. Water treatment required to obtain these four levels of quality is described in the following paragraphs.

2.2.7.4.1 Water for the Circulating Water System

Water used for makeup in the circulating water system will be fed directly from the pipeline water supply into two 1.5-million-gallon aboveground raw/fire water storage tanks. These tanks will provide approximately 17 hours of operational storage for a maximum flow of 2,638 gallons per minute (gpm) in the event that there is a disruption in the flow of reclaimed water. In addition, the tanks will provide 2 hours of fire protection water storage at a flow rate of 2,000 gpm. Makeup water will be fed from the storage tanks to the cooling tower basin as required to replace water lost from evaporation, drift, and blowdown.

A chemical feed system will supply water conditioning chemicals to the circulating water to minimize corrosion and control the formation of mineral scale and biofouling. Sulfuric acid will be fed into the circulating water system in proportion to makeup water flow for alkalinity reduction to control the scaling tendency of the circulating water.

The acid feed equipment will consist of a bulk sulfuric acid storage tank and two full-capacity sulfuric acid metering pumps.

To further inhibit scale formation, a polyacrylate solution will be fed into the circulating water system as a sequestering agent in an amount proportional to the circulating water blowdown flow. The scale inhibitor feed equipment will consist of a chemical solution bulk storage tank and two full-capacity scale inhibitor metering pumps.

To prevent biofouling in the circulating water system, sodium hypochlorite will be fed into the system. The hypochlorite feed equipment will consist of a bulk storage tank and two full-capacity hypochlorite metering pumps. A bulk storage tank, 200- to 400-gallon totes, and two full-capacity metering pumps will be provided for the feeding of either stabilized bromine or sodium bromide as alternate biocides.

2.2.7.4.2 Service Water

Service water includes all water uses at the plant except for the circulating water previously discussed, demineralized water used in the HRSG and auxiliary boiler, and domestic water (see following section). Filtered cooling tower blowdown will be used for service water. Service water will be stored in an aboveground steel tank.

2.2.7.4.3 Makeup Water for the HRSGs and Auxiliary Boiler

Demineralized water will be used for makeup water for the HRSGs and auxiliary boiler. The demineralized water will be produced by passing distillate through mixed bed ion exchange demineralizers. The source of distillate will be from one of the following: (1) during normal operation, sufficient distillate will be produced by the brine concentrator, which is part of the zero-liquid discharge system that recovers water from the cooling tower blowdown; (2) during peak load operation, the quantity of brine concentrator distillate will be insufficient to meet the demands for makeup to the demineralized water system. In this case, the brine concentrator distillate will be supplemented with reclaimed water that has been filtered and purified via a reverse osmosis system to remove suspended solids and most of the dissolved solids. The demineralized water will be stored in two 250,000-gallon demineralized water storage tanks.

HRSG and auxiliary boiler makeup water will be drawn from the demineralized water storage tanks. Demineralized water will also be used for CTG inlet air fogging (used to increase turbine output) and for CTG wash water.

Additional conditioning of the water in the HRSGs and auxiliary boiler, to minimize corrosion and scale formation, will be provided by chemical feed systems. The systems will feed an oxygen scavenger to the condensate for dissolved oxygen control, a neutralizing amine to the condensate for corrosion control, and a phosphate solution to the HRSG steam drums for pH and alkalinity control. The design will provide for automatic feed of the oxygen scavenger in proportion to condensate flow and the amine in proportion to condensate flow with a pH bias. The system will include an oxygen scavenger solution feed tank and two full-capacity, chemical feed pumps and an amine solution feed tank and two full-capacity chemical feed pumps.

The phosphate feed system will be designed for operation using the low solids, congruent phosphate or other standard method of boiler water treatment. The design will provide for feeding phosphates to the boiler water to react with any hardness present. The phosphate feed will be manually initiated based on boiler water phosphate residual and pH. One solution tank and full-capacity phosphate feed pump will be provided for each steam (HP and IP) drum with one common spare pump serving each HRSG.

2.2.7.4.4 HRSG and Auxiliary Boiler Steam Cycle Sampling and Analysis System

This system will monitor the water quality at various points in the HRSG and auxiliary boiler steam cycle and provide sufficient data to operating personnel for detection of deviations from control limits so that corrective action can be taken. The samples will be routed to a sample panel, located in the water treatment facility, where pressure and temperature will be reduced as required. At the sample panel, samples will be directed to automatic analyzers for continuous monitoring, and grab samples will be provided for wet chemical analysis. All monitored values will be indicated at the sample panel.

Automatic analyzers will monitor cation conductivity, pH, sodium, dissolved oxygen, and specific conductance.

2.2.8 Plant Cooling Systems

The cycle heat rejection system will consist of a deaerating steam surface condenser, cooling tower, and circulating water system. The heat rejection system will receive exhaust steam from the low-pressure steam turbine and condense it to water for reuse. The surface condenser will be a shell-and-tube heat exchanger with the steam condensing on the shell side and the cooling water flowing in one or more passes inside the tubes. The condenser will be designed to operate at sub-atmospheric pressure, ranging from 1 to 5 inches of mercury, absolute (Hga), depending on ambient temperature and plant load. It will remove between 1,700 and 3,000 MMBtu/hr, depending on ambient temperature and plant load. Approximately 212,163 gpm of circulating cooling water is required to condense the steam at maximum plant load.

The circulating water will circulate through a counter-flow mechanical draft cooling tower, which uses electric-motor-driven fans to move the air in a direction opposite to the flow of the water. The heat removed in the condenser will be discharged to the atmosphere by heating the air and through evaporation of some of the circulating water. Maximum drift, that is, the fine mist of water droplets entrained in the warm air leaving the cooling tower, will be limited to 0.0005 percent of the circulating water flow.

A closed-loop auxiliary cooling system will be provided for cooling plant equipment other than the steam condenser. Equipment served by the auxiliary cooling water system includes the CTG and STG lube oil coolers, STG generator cooler, STG hydraulic control system cooler, boiler feed pump lube oil and seal water coolers, air compressor, vacuum pump seal coolers, and sample coolers. Auxiliary cooling water pumps will pump circulating water from the cooling tower basin through heat exchangers to remove heat from the closed loop system.

2.2.9 Waste Management

Waste management is the process whereby all wastes produced at CVEC are properly collected, treated if necessary, and disposed of. Wastes include wastewater, solid nonhazardous waste, and hazardous waste, both liquid and solid. Waste management is discussed in more detail in Section 8.13.

2.2.9.1 Wastewater Collection, Treatment, and Disposal

The primary wastewater collection system will collect process wastewater from all of the plant equipment, including the HRSGs, cooling tower, and water treatment equipment. Since CVEC is a zero liquid discharge facility, process wastewater will be reclaimed and reused, to the extent possible. The leftover concentrated brine solution, high in total dissolved solids (TDS), will be dried in a drum dryer to a solid salt precipitate. The precipitate will be non-hazardous and be taken off-site for disposal in a municipal landfill, as described in Section 8.13. The water balance diagrams, Figures 2.2-6a and 2.2-6b, show the expected wastewater streams and flow rates for CVEC. The second wastewater collection system will collect sanitary wastewater from sinks, toilets, showers, and other sanitary facilities, and discharge it to the City of San Joaquin sanitary sewer system. The two wastewater systems are described below.

2.2.9.1.1 Circulating Water System Blowdown

Circulating water system blowdown will consist of reclaimed water from Fresno-Clovis WWTF along with various process waste streams that have been concentrated between three and eight times and residues of the chemicals added to the circulating water. These chemicals control scaling and biofouling of the cooling tower and control corrosion of the circulating water piping and condenser. Cooling tower blowdown will be discharged to a zero-liquid discharge treatment system, where most of the water will be reclaimed for reuse within the plant.

2.2.9.1.2 Zero Liquid Discharge Treatment System

The ZLD at CVEC makes use of three concentration steps – the cooling tower, a high TDS reverse osmosis system, and a brine concentrator. All process waste streams (oil/water separator effluent, quenched HRSG blowdown, and makeup reverse osmosis reject) are directed to the cooling tower for initial concentration. The cooling tower concentrates these streams near the mineral solubility limit for the constituents of concern (calcium and silica). This concentrated water must then be removed from the cooling tower via blowdown to prevent the formation of mineral scale in heat transfer equipment.

Cooling tower blowdown is stored to minimize flow variation in downstream ZLD equipment. After blowdown storage, cooling tower blowdown is passed through a multimedia filter to removed suspended solids. Suspended solids removal is required to minimize fouling of downstream ZLD equipment.

Cooling tower blowdown is near the mineral solubility limit for two components – calcium and silica. After filtration, the cooling tower blowdown is passed through weak acid cation resin to remove calcium. The weak acid cation resin is regenerated with sodium. The blowdown water then passes through a second weak acid cation vessel to remove the remaining calcium. Lowering calcium concentration prevents calcium scale formation in the high TDS reverse osmosis system. Waste from weak acid cation regeneration is neutralized and then sent directly to the brine concentrator feed storage tank for final concentration.

Although calcium-free, the treated cooling tower blowdown still contains silica concentrated to near the mineral solubility limit. Without treatment, this silica would form scale on the high TDS reverse osmosis membranes. Silica solubility, however, increases as pH increases. Thus, caustic is injected in the cooling tower blowdown stream prior to the high TDS reverse osmosis system. Caustic injection raises the silica solubility limit and minimizes the potential for scale formation in the high TDS reverse osmosis unit.

High TDS reverse osmosis represents the second concentrating step in the ZLD system. The high TDS reverse osmosis unit recovers approximately 90 percent of the remaining cooling tower blowdown. Permeate from the high TDS reverse osmosis system contains low levels of silica and calcium. This relatively “good” water is returned to the cooling tower to minimize makeup water usage. The high TDS reverse osmosis reject, approximately 10 percent of the influent flow, contains high levels of silica and calcium. Since it is unusable in the plant, this small flow is directed to the brine concentrator for final concentration.

The brine concentrator receives high TDS waste from the weak acid cation vessels and the high TDS reverse osmosis reject. Heat is applied to evaporate approximately 96 percent of the water contained in these two waste streams. Evaporated water is reclaimed using a condenser. This distillate contains very little TDS. It is stored in a distillate storage tank, combined with makeup reverse osmosis permeate, and passed through a mixed-bed demineralizer (regenerated off-site). Demineralized water exiting the mixed bed demineralizer is stored in the demineralized water storage tank for use in the combustion turbines and HRSG steam cycle. The concentrated brine is sent to a drum dryer.

The drum dryer uses applied heat to accomplish evaporation to dryness. Dry, non-hazardous solids will be captured in bins and trucked off-site for disposal. Naturally occurring substances, such as trace heavy metals present in the cooling water, will become concentrated in the salt cake product from the ZLD system.

2.2.9.1.3 Plant Drains and Oil/Water Separator

General plant drains will collect area washdown, sample drains, and drainage from facility equipment areas. Water from these areas will be collected in a system of floor drains, hub drains, sumps, and piping and routed to the wastewater collection system. Drains that potentially could contain oil or grease will first be routed through an oil/water separator. Water from the plant wastewater collection system will be reclaimed to the cooling tower basin. Wastewater from combustion turbine water washes will be collected in a holding tank. If cleaning chemicals were not used during the water wash procedure, the wastewater will be discharged to the oil/water separator. Wastewater containing cleaning chemicals will be trucked offsite for disposal at an approved wastewater disposal facility.

2.2.9.1.4 Power Cycle Makeup Water Treatment Wastes

Wastewater from the power cycle makeup water treatment system will consist of the reject stream from the makeup reverse osmosis (RO) units that will initially reduce the concentration of dissolved solids in the plant makeup water before it is treated in the mixed bed ion exchange vessels and backwash water from the multi-media filters upstream of the RO units. The RO reject stream will contain the constituents of the reclaimed water, concentrated approximately four times; residues of the chemicals such as aluminum sulfate, ferric chloride, and polymer added to the reclaimed water to coagulate suspended solids prior to filtration; sodium bisulfite or sodium sulfite added to the RO feedwater to eliminate free chlorine that would otherwise damage the RO membranes; and phosphate to prevent scaling of the membranes. The filter backwash water will contain the suspended solids removed from the reclaimed water and residues of the coagulants used to enhance filtration efficiency. These waste streams will be collected and reclaimed to the cooling tower basin along with the plant drains and permeate from the high TDS RO units.

2.2.9.1.5 HRSG and Auxiliary Boiler Blowdown

HRSG blowdown will consist of boiler water discharged from the HRSG steam drums to control the concentration of dissolved solids and silica within acceptable ranges. Boiler blowdown will be discharged to flash tanks where the steam is vented to atmosphere and the condensate is cooled by mixing it with a small amount of circulating water. The quenched condensate will be discharged to the cooling tower basin, thus reclaiming the majority of the boiler blowdown.

2.2.9.1.6 Solid Wastes

CVEC will produce maintenance and plant wastes typical of power generation operations. Generation plant wastes include oily rags, broken and rusted metal and machine parts, defective or broken electrical materials, empty containers, and other solid wastes, including the typical refuse generated by workers. Additionally, CVEC will generate dry, non-hazardous solids from the ZLD system, as discussed above. These materials will be collected by the local waste disposal company (see Section 8.13). Recyclable materials will be taken offsite. Waste collection and disposal will be in accordance with applicable regulatory requirements to minimize health and safety effects.

2.2.9.1.7 Hazardous Wastes

Several methods will be used to properly manage and dispose of hazardous wastes generated by CVEC. Waste lubricating oil will be recovered and reclaimed by a waste oil recycling contractor. Spent lubrication oil filters will be disposed of in a Class I landfill. Spent SCR and oxidation catalysts will be reclaimed by the supplier or disposed of in accordance with regulatory requirements. Workers will be trained to handle hazardous wastes generated at the site.

Chemical cleaning wastes will consist of alkaline and acid cleaning solutions used during pre-operational chemical cleaning of the HRSGs, acid cleaning solutions used for chemical cleaning of the HRSGs after the units are put into service, and turbine wash and HRSG fireside washwaters. These wastes, which are subject to high metal concentrations, will be temporarily stored onsite in portable tanks, and disposed of offsite by the chemical cleaning contractor in accordance with applicable regulatory requirements.

2.2.10 Management of Hazardous Materials

There will be a variety of chemicals stored and used during construction and operation of CVEC project. The storage, handling, and use of all chemicals will be conducted in accordance with applicable LORS. Chemicals will be stored in appropriate chemical storage facilities. Bulk chemicals will be stored in storage tanks, and other chemicals will be stored in returnable delivery containers. Chemical storage and chemical feed areas will be designed to contain leaks and spills. Berm and drain piping design will allow a full-tank capacity spill without overflowing the berms. For multiple tanks located within the same bermed area, the capacity of the largest single tank will determine the volume of the bermed area and drain piping. Drain piping for volatile chemicals will be trapped and isolated from other drains to eliminate noxious or toxic vapors. After neutralization, if required, water collected from the chemical storage areas will be directed to the cooling tower basin.

The anhydrous ammonia storage area will have a water spray system, spill containment, and ammonia vapor detection equipment.

Safety showers and eyewashes will be provided adjacent to or in the vicinity of all chemical storage and use areas. Hose connections will be provided near the chemical storage and feed areas to flush spills and leaks to the plant wastewater collection system. Approved personal protective equipment will be used by plant personnel during chemical spill containment and cleanup activities. Personnel will be properly trained in the handling of these chemicals and instructed in the procedures to follow in case of a chemical spill or accidental release. Adequate supplies of absorbent material will be stored onsite for spill cleanup.

A list of the chemicals anticipated to be used at the generating facility and their locations is provided in the Hazardous Materials Handling section (Section 8.12). This list identifies each chemical by type, intended use, and estimated quantity to be stored on site. Section 8.12 includes additional information on hazardous materials handling.

2.2.11 Emission Control and Monitoring

Air emissions from the combustion of natural gas in the CTGs and duct burners will be controlled using state-of-the-art systems. Emissions that will be controlled include NO_x, reactive organic compounds (ROCs), CO, and particulate matter. To ensure that the systems perform correctly, continuous emissions monitoring will be performed. Section 8.1, Air Quality, includes additional information on emission control and monitoring.

2.2.11.1 NO_x Emission Control

SCR will be used to control NO_x concentrations in the exhaust gas emitted to the atmosphere to 2.5 ppmvd at 15 percent oxygen from the gas turbines/HRSGs (2.0 ppmvd on an average annual basis). NO_x emissions will be controlled to 9 ppmvd at 3 percent oxygen from the auxiliary boiler. The SCR process will use anhydrous ammonia. Ammonia slip, or the concentration of unreacted ammonia in the exiting exhaust gas, will be limited to 10 ppmvd at 15 percent oxygen from the gas turbines/HRSGs; if SCR is used to control NO_x on the auxiliary boiler, the ammonia slip will be limited to 10 ppmvd at 3 percent oxygen from the auxiliary boiler. The SCR equipment will include a reactor chamber, catalyst modules, ammonia storage system, ammonia vaporization and injection system, and monitoring equipment and sensors.

2.2.11.2 Carbon Monoxide

An oxidizing catalytic converter will be used to reduce the CO concentration in the exhaust gas emitted to the atmosphere to 6 ppmvd at 15 percent oxygen from the gas turbines; CO emissions will be controlled to 50 ppmvd at 3 percent oxygen from the auxiliary boiler.

2.2.11.3 Particulate Emission Control

Particulate emissions will be controlled by the use of natural gas, which is low in particulates, as the sole fuel for the CTGs and auxiliary boiler.

2.2.11.4 Continuous Emission Monitoring

Continuous emission monitors (CEMs) will sample, analyze, and record fuel gas flow rate, NO_x and CO concentration levels, and percentage of O_2 in the exhaust gas from the three HRSG stacks and from the auxiliary boiler stack. This system will generate reports of emissions data in accordance with permit requirements and will send alarm signals to the plant distributed control system (DCS) when the emissions approach or exceed pre-selected limits.

2.2.12 Fire Protection

The fire protection system will be designed to protect personnel and limit property loss and plant downtime in the event of a fire. There will be a dedicated fire water storage supply of a minimum of 240,000 gallons in the raw/fire water storage tanks. The dedicated water supply is sized in accordance with National Fire Protection Association (NFPA) guidelines to provide 2 hours of protection from the onsite worst-case single fire. These water storage tanks will include a standpipe on the cooling tower makeup supply line so that the dedicated fire water portion of the storage tanks cannot be used for other purposes.

An electric jockey pump and electric-motor-driven main fire pump will be provided to increase the water pressure in the plant fire main pump to the level required to serve all fire fighting systems. In addition, a diesel engine-driven fire pump will be provided to pressurize the fire loop if the power supply to the main fire pump fails. A fire pump controller will be provided for the back-up fire pump.

All three fire pumps will discharge to a dedicated underground fire loop piping system. Both the fire hydrants and the fixed suppression systems will be supplied from the fire water loop. Fixed fire suppression systems will be installed at determined fire risk areas such as the transformers and turbine lube oil equipment. Sprinkler systems will also be installed in the Administration/Maintenance Building and Fire Pump enclosure as required by NFPA and local code requirements. The CTG units will be protected by an FM200 fire protection system. Hand-held fire extinguishers of the appropriate size and rating will be located in accordance with NFPA 10 throughout the facility. The cooling tower will be constructed of fiberglass having a flame-spread rating of 25 or less and will therefore not be sprinklered.

Section 8.12, Hazardous Materials Handling, includes additional information for fire and explosion risk, and Section 8.8, Socioeconomics, provides information on local fire protection capability.

2.2.13 Plant Auxiliaries

The following systems will support, protect, and control the generating facility.

2.2.13.1 Lighting

The lighting system provides personnel with illumination for operation under normal conditions and for egress under emergency conditions, and includes emergency lighting to perform manual operations during an outage of the normal power source. The system also provides 120-volt convenience outlets for portable lamps and tools.

2.2.13.2 Grounding

The electrical system is susceptible to ground faults, lightning, and switching surges that result in high voltage that constitute a hazard to site personnel and electrical equipment. The station grounding system provides an adequate path to permit the dissipation of current created by these events.

The station grounding grid will be designed for adequate capacity to dissipate heat from ground current under the most severe conditions in areas of high ground fault current concentration. The grid spacing will maintain safe voltage gradients.

Bare conductors will be installed below-grade in a grid pattern. Each junction of the grid will be bonded together by an exothermic weld.

Ground resistivity readings will be used to determine the necessary numbers of ground rods and grid spacing to ensure safe step and touch potentials under severe fault conditions.

Grounding stingers will be brought from the ground grid to connect to building steel and non-energized metallic parts of electrical equipment.

2.2.13.3 Distributed Control System

The DCS provides modulating control, digital control, monitoring, and indicating functions for the plant power block systems.

The following functions will be provided:

- Controlling the STG, CTGs, HRSGs, and other systems in a coordinated manner
- Controlling the balance-of-plant systems in response to plant demands

- Monitoring controlled plant equipment and process parameters and delivery of this information to plant operators
- Providing control displays (printed logs, cathode ray tube [CRT]) for signals generated within the system or received from input/output (I/O)
- Providing consolidated plant process status information through displays presented in a timely and meaningful manner
- Providing alarms for out-of-limit parameters or parameter trends, displaying on alarm CRT(s), and recording on an alarm log printer
- Providing storage and retrieval of historical data

The distributed control system will be a redundant microprocessor-based system and will consist of the following major components:

- CRT-based operator consoles
- Engineer work station
- Distributed processing units
- I/O cabinets
- Historical data unit
- Printers
- Data links to the combustion turbine and steam turbine control systems

The DCS will have a functionally distributed architecture comprising a group of similar redundant processing units linked to a group of operator consoles and the engineer work station by redundant data highways. Each processor will be programmed to perform specific dedicated tasks for control information, data acquisition, annunciation, and historical purposes. By being redundant, no single processor failure can cause or prevent a unit trip.

The DCS will interface with the control systems furnished by the CTG and STG suppliers to provide remote control capabilities, as well as data acquisition, annunciation, and historical storage of turbine and generator operating information.

The system will be designed with sufficient redundancy to preclude a single device failure from significantly affecting overall plant control and operation. This also will allow critical control and safety systems to have redundancy of controls, as well as an uninterruptible power source.

As part of the quality control program, daily operator logs will be available for review to determine the status of the operating equipment.

2.2.13.4 Cathodic Protection

The cathodic protection system will be designed to control the electrochemical corrosion of designated metal piping buried in the soil. Depending upon the corrosion potential and the site soils, either passive or impressed current cathodic protection will be provided.

2.2.13.5 Freeze Protection

The freeze protection system will provide heating to protect various outdoor piping, gauges, pressure switches, and other devices from freezing. Power to the self-limiting freeze protection circuits will be controlled by an ambient thermostat.

2.2.13.6 Service Air

The service air system will supply compressed air to hose connections for general plant use. Service air headers will be routed to hose connections located at various points throughout the facility.

2.2.13.7 Instrument Air

The instrument air system provides dry air to pneumatic operators and devices. An instrument air header will be routed to locations within the facility equipment areas and within the water treatment facility where pneumatic operators and devices will be located.

2.2.14 Interconnect to Electrical Grid

The three CTGs and one STG will each be connected to PG&E's transmission system by looping into the Panoche – McCall and Panoche – Kearney 230-kV transmission lines.

2.2.15 Project Construction

Construction of the generating facility, from site preparation and grading to commercial operation, is expected to take place from third quarter 2002 to third quarter 2004, (24 months, up to 27 months total). Major milestones are listed in Table 2.2-2.

TABLE 2.2-2
Project Schedule Major Milestones

Activity	Date
Begin Construction	Third Quarter 2002
Startup and Test	Second Quarter 2004
Commercial Operation	Third Quarter 2004

There will be an average and peak workforce of approximately 205 and 386, respectively, of construction craft people, supervisory, support, and construction management personnel on site during construction (see Table 8.8-8).

Construction will be scheduled to occur between 6 a.m. and 6 p.m., Monday through Saturday. Additional hours may be necessary to make up schedule deficiencies, or to complete critical construction activities. During some construction periods and during the startup phase of the project, some activities will continue 24 hours per day, 7 days per week.

The peak construction site workforce level is expected to last from Month 11 through Month 17 of the construction period.

Table 2.2-3 provides an estimate of the average and peak construction traffic during the appropriate 24-month (up to 27 months) construction period.

TABLE 2.2-3
Average and Peak Construction Traffic

Vehicle Type	Average Daily Trips	Peak Daily Trips
Construction Workers	315	594
Delivery	2	6
Heavy Trucks	10	20
Total	**327**	**620**

Construction laydown and parking areas will be within approximately 20 acres located on the CVEC site, north of the plant area. Construction access will be from Colorado Avenue to Manning to Colusa, to Cherry Lane, as shown on Figure 2.1-1. Materials and equipment could be delivered by truck or rail. Construction of a temporary rail spur from the existing railroad line, bordering the east side of the project site for delivery of large equipment modules is being considered.

2.2.16 Generating Facility Operation

CVEC will be operated by 3 operators per 12-hour rotating shift, plus 3 relief operators and one chemical technician, 7 maintenance technicians, and 7 administrative personnel during the standard 8-hour work day (Table 2.2-4). The facility will be operated 7 days a week, 24 hours per day.

TABLE 2.2-4
CVEC Staffing Plan

Plant Manager	Maintenance Manager[a]	Operations Manager[a]		
Plant Engineer	I&E Technician	"A" Operator	"B" Operator	"C" Operator
Office Manager	I&E Technician	"A" Operator	"B" Operator	"C" Operator
Plant Administrator	I&E Technician	"A" Operator	"B" Operator	"C" Operator
Purchasing/Warehouse Technician	Electrical Technician	"A" Operator	"B" Operator	"C" Operator
	Maintenance Technician	"A" Operator	"B" Operator	"C" Operator
	Maintenance Technician	Chemical Technician		
	Maintenance Technician			

[a] Report to Plant Manager.

CVEC is expected to have an annual plant availability of 92 to 98 percent. It will be possible for plant availability to exceed 98 percent for a given 12-month period. The exact operational profile of the plant, however, cannot be defined since the facility will be operating in and selling electricity to a deregulated electric power sales market.

CVEC will sell all or part of its generation under contract. Generation available from CVEC that has not been sold through contracts will be available for sale on the spot market. Operation of CVEC therefore depends on the quantity of electricity sold through contracts and the ability of CVEC to sell into the competitive spot market.

Because the capacity that will be sold through contract and the prices that will be offered for spot purchases are unknown at this time, the exact mode of operation of CVEC cannot be described. It is conceivable, however, that the facility could be operated in one or all of the following modes:

- **Base Load**. The facility would be operated at maximum continuous output for as many hours per year as is profitable. During high ambient temperature periods when gas turbine output would otherwise decrease, duct firing and/or power augmentation by steam injection into the combustion turbines may be employed to keep plant output at the sum of contractual load and spot market sales.
- **Load Following**. The facility would be operated to meet contractual load and whatever spot sales could be made, but the sum would be less than maximum continuous output at all times of the day. The output of the unit would therefore be adjusted periodically to meet whatever load proved profitable to the facility.

- **Partial Shutdown**. At certain times of any given day and at certain times of any given year, the sum of the contractual load and spot market sales can be expected to drop to a level at which it would be economically favorable to shut down one or two CTG(s)/HRSG(s). This mode of operation can be expected to occur during late evening and early morning hours and on weekends when contractual load could decrease or spot market sales would not be economical.
- **Full Shutdown**. This would occur if forced by equipment malfunction, fuel supply interruption, transmission line disconnect, or scheduled maintenance. Full shutdown could also occur when the market price of electricity is less than CVEC incremental cost of generation. The facility is limited in operation below maximum continuous output (base load) by economics since gas turbine efficiency decreases sharply as output is decreased. The facility would also experience operational problems including exceedance of air quality limits at outputs below 60 percent of CTG output.

In the unlikely event of a situation that causes a longer-term cessation of operations, security of the facilities will be maintained on a 24-hour basis, and the California Energy Commission (CEC) will be notified. Depending on the length of shutdown, a contingency plan for the temporary cessation of operations may be implemented. Such contingency plan will be in conformance with all applicable LORS and protection of public health, safety, and the environment. The plan, depending on the expected duration of the shutdown, could include the draining of all chemicals from storage tanks and other equipment and the safe shutdown of all equipment. All wastes will be disposed of according to applicable LORS. If the cessation of operations becomes permanent, the plant will be decommissioned (see Section 4.0, Facility Closure).

2.3 Facility Safety Design

CVEC will be designed to maximize safe operation. Potential hazards that could affect the facility include earthquake, flood, and fire. Facility operators will be trained in safe operation, maintenance, and emergency response procedures to minimize the risk of personal injury and damage to the plant.

2.3.1 Natural Hazards

The principal natural hazard associated with the CVEC site is earthquakes. The site is located in Seismic Risk Zone 3. Structures will be designed to meet the seismic requirements of CCR Title 24 and the 1998 California Building Code (CBC). (See Section 8.15, Geologic Hazards and Resources.) This section includes a review of potential geologic hazards, seismic ground motion, and potential for soil liquefaction due to ground-shaking. Potential seismic hazards would be mitigated by implementing the 1998 CBC construction guidelines. Appendix 10B, Structural Engineering, includes the structural seismic design criteria for the buildings and equipment.

Flooding is not a hazard of concern. According to the Federal Emergency Management Agency (FEMA), the site is not within either the 100- or 500-year flood plain. Section 8.14, Water Resources, includes additional information on the potential for flooding.

2.3.2 Emergency Systems and Safety Precautions

This section discusses the fire protection systems, emergency medical services, and safety precautions to be used by project personnel. Section 8.8, Socioeconomics, includes additional information on area medical services, and Section 8.7, Worker Safety, includes additional information on safety for workers. Appendices 10A through 10G contain the design practices and codes applicable to safety design for the project. Compliance with these requirements will minimize project effects on public and employee safety.

2.3.2.1 Fire Protection Systems

The project will rely on both onsite fire protection systems and local fire protection services.

2.3.2.1.1 Onsite Fire Protection Systems

The fire protection systems are designed to protect personnel and limit property loss and plant downtime from fire or explosion. The project will have the following fire protection systems.

FM 200 Fire Protection System

This system protects the combustion turbine, generator, and accessory equipment compartments from fire. The system will have fire detection sensors in all compartments. Actuating one sensor will provide a high-temperature alarm on the combustion turbine control panel. Actuating a second sensor will trip the combustion turbine, turn off ventilation, close ventilation openings, and automatically release the FM 200. The FM 200 will be discharged at a design concentration adequate to extinguish the fire.

Transformer Deluge Spray System

This system provides fire suppression for the generator transformers and auxiliary power transformers in the event of a fire. The deluge systems are fed by the plant underground fire water system.

Steam Turbine Bearing Preaction Water Spray System

This system provides suppression for the steam turbine bearing in the event of fire. The preaction system is fed by the plant underground fire water system.

Steam Turbine Lube Oil Areas Water Spray System

This system provides suppression for the steam turbine area lube oil piping and lube oil storage.

Fire Hydrants/Hose Stations

This system will supplement the plant fire protection system. Water will be supplied from the plant underground fire water/domestic water system.

Fire Extinguisher

The plant Administrative/Maintenance Building, water treatment facility, and other structures will be equipped with portable fire extinguishers as required by the local fire department.

2.3.2.1.2 Local Fire Protection Services

In the event of a major fire, the plant personnel will be able to call upon the Fresno County Fire Department for assistance. The Hazardous Materials Risk Management Plan (see Section 8.12, Hazardous Materials Handling) for the plant will include all information necessary to permit all fire-fighting and other emergency response agencies to plan and implement safe responses to fires, spills, and other emergencies.

2.3.2.2 Personnel Safety Program

The CVEC project will operate in compliance with federal and state occupational safety and health program requirements. Compliance with these programs will minimize project effects on employee safety. These programs are described in Section 8.7, Worker Safety.

2.4 Facility Reliability

This section discusses the expected facility availability, equipment redundancy, fuel availability, water availability, and project quality control measures.

2.4.1 Facility Availability

Because of CVEC's predicted high efficiency, it is anticipated that the facility will normally be called upon to operate at high average annual capacity factors. The facility will be designed to operate between 25 and 100 percent of base load to support dispatch service in response to customer demands for electricity.

CVEC will be designed for an operating life of 30 years. Reliability and availability projections are based on this operating life. Operation and maintenance procedures will be consistent with industry standard practices to maintain the useful life status of plant components.

The percent of time that the combined-cycle power plant (and the HRSG duct burners) is projected to be operated is defined as the "service factor." The service factor considers the amount of time that a unit is operating and generating power, whether at full or partial load. The projected service factor for the combined-cycle power block, which considers projected percent of time of operation, differs from the equivalent availability factor (EAF), which considers the projected percent of energy production capacity achievable.

The EAF may be defined as a weighted average of the percent of full energy production capacity achievable. The projected equivalent availability factor for CVEC is estimated to be approximately 92 to 98 percent.

The EAF, which is a weighted average of the percent of energy production capacity achievable, differs from the "availability of a unit," which is the percent of time that a unit is available for operation, whether at full load, partial load, or standby.

2.4.2 Redundancy of Critical Components

The following subsections identify equipment redundancy as it applies to project availability. A summary of equipment redundancy is shown in Table 2.4-1. Final design could differ.

TABLE 2.4-1
Major Equipment Redundancy

Description	Number	Note
Combined cycle CTGs and HRSGs	Three trains	Steam turbine bypass system allows all three CTG/HRSG trains to operate at base load with the steam turbine out of service.
STG	One	See note above pertaining to CTGs and HRSGs.
HRSG feedwater pumps	Two – 100 percent per HRSG	--
Condensate pumps	Three - 50 percent capacity	--
Condenser	One	Condenser must be in operation for combined cycle operation or operation of CTG in steam turbine bypass mode. The condenser will be provided with split water boxes to allow online tube cleaning and repair.
Circulating water pumps	Two – 50 percent capacity	
Cooling tower	One	Cooling tower is multi-cell mechanical draft design. Basin will be divided (8 cells/8 cells) to allow a portion to be isolated for cleaning.

TABLE 2.4-1
Major Equipment Redundancy

Description	Number	Note
Auxiliary cooling water pumps	Two – 100 percent capacity	--
Closed-loop cooling water pumps	Two – 100 percent capacity	--
Closed-loop cooling water heat exchangers	Two – 100 percent capacity	--
Demineralizer—RO Systems	Three - 50 percent capacity trains	Redundant pumps will be provided.

2.4.2.1 Combined-cycle Power Block

Three separate combustion turbine/HRSG power generation trains will operate in parallel within the combined-cycle power block. Each train will be powered by a combustion turbine. Each CTG will provide approximately 17 to 22 percent of the total combined-cycle power block output. The heat input from the exhaust gas from each combustion turbine will be used in the steam generation system to produce steam. Heat input to each HRSG can be supplemented by firing the HRSG duct burners, which will increase steam flow from the HRSG. Thermal energy from the steam generation system will be converted to mechanical energy, and then electrical energy in the STG subsystem. The expanded steam from the steam turbine will be condensed and reclaimed to the feedwater system. Power from the STG subsystem will contribute approximately 35 to 50 percent of total combined-cycle power block output.

The major components of the combined-cycle power block consist of the following subsystems.

2.4.2.1.1 Combustion Turbine Generator Subsystems

The combustion turbine subsystems include the combustion turbine, inlet air filtration and fogging system, generator and excitation systems, and turbine control and instrumentation. The combustion turbine will produce thermal energy through the combustion of natural gas and the conversion of the thermal energy into mechanical energy through rotation of the combustion turbine that drives the compressor and generator. Power output can be increased through steam injection upstream of the power turbine section of the CTG. Exhaust gas from the combustion turbine will be used to produce steam in the associated HRSG. The generator will be air cooled. The generator excitation system will be a solid-state static system. Combustion turbine control and instrumentation (interfaced with the DCS) will cover the turbine governing system, and the protective system.

2.4.2.1.2 Steam Generation Subsystems

The steam generation subsystems consist of the HRSG, auxiliary boiler, and blowdown systems. The HRSG transfers heat from the CTG exhaust gas and from supplemental combustion of natural gas in the HRSG duct burner for steam production. This heat transfer produces steam at the pressures and temperatures required by the steam turbine. Each HRSG system consists of ductwork, heat transfer sections, an SCR system, a CO catalyst module, and exhaust stack. The auxiliary boiler provides for STG gland steam, HRSG sparging steam, condenser hotwell sparging steam, and deaeration steam when the plant is off-line. The blowdown system provides vents and drains for each HRSG. The system includes safety and auto relief valves and processing of continuous and intermittent blowdown streams.

2.4.2.1.3 Steam Turbine Generator Subsystems

The steam turbine converts the thermal energy in the steam to mechanical energy to drive the STG. The basic subsystems include the steam turbine and auxiliary systems, turbine lube oil system, and generator/exciter system. The generator will be hydrogen cooled.

The combined-cycle power block is served by the following balance-of-plant systems.

2.4.2.2 Distributed Control System

The DCS will be a redundant microprocessor-based system that will provide the following functions:

- Control the HRSGs, STG, CTG, and other systems in response to unit load demands (coordinated control)
- Provide control room operator interface
- Monitor plant equipment and process parameters and provide this information to the plant operators in a meaningful format
- Provide visual and audible alarms for abnormal events based on field signals or software-generated signals from plant systems, processes, or equipment

The DCS will have functionally distributed architecture comprising a group of similar redundant processing units linked to a group of operator consoles and an engineer workstation by redundant data highways. Each processor will be programmed to perform specific dedicated tasks for control information, data acquisition, annunciation, and historical purposes.

Plant operation will be controlled from the operator panel located in the control room. The operator panel will consist of two individual CRT/keyboard consoles and one engineering workstation. Each CRT/keyboard console will be an independent electronic package so that failure of a single package does not disable more than one CRT/keyboard. The engineering workstation will allow the control system operator interface to be revised by authorized personnel.

2.4.2.3 Boiler Feedwater System

The boiler feedwater system transfers feedwater from the LP drum to the HP and IP sections of the HRSGs. The system will consist of two pumps per HRSG, each pump sized for 100 percent capacity for supplying one HRSG. The pumps will be multistage, horizontal, motor-driven with intermediate bleed-off, and will include regulating control valves, minimum flow recirculation control, and other associated piping and valves.

2.4.2.4 Condensate System

The condensate system will provide a flow path from the condenser hotwell to the HRSG LP drum and boiler feed pumps. The condensate system will include three 50 percent capacity multistage, vertical, motor-driven condensate pumps.

2.4.2.5 Demineralized Water System

Makeup to the demineralized water system will be from one of the sources described above in the Water Supply Section. The demineralized water system will consist of three 50 percent capacity makeup RO and mixed-bed demineralizer trains. Demineralized water will be stored in two 250,000-gallon demineralized water storage tanks.

2.4.2.6 Power Cycle Makeup and Storage

The power cycle makeup and storage subsystem provides demineralized water storage and pumping capabilities to supply high-purity water for system cycle makeup and chemical cleaning operations. Major components of the system are the demineralized water storage tanks, providing an approximate 9-hour supply of demineralized water at peak load or an approximate 4.5-day supply at base load (no duct firing or power augmentation), and two full-capacity, horizontal, centrifugal, cycle makeup water pumps.

2.4.2.7 Circulating Water System

The circulating water system provides cooling water to the condenser for condensing steam turbine exhaust and steam turbine bypass steam. In addition, the system supplies cooling water to the closed-loop cooling water heat exchangers. Major components for this subsystem are two 50 percent, motor-driven vertical circulating water pumps, two 100 percent auxiliary cooling water pumps, and associated piping and valves, as required.

2.4.2.8 Closed-loop Cooling Water System

The closed-loop cooling water system transfers heat from various plant equipment heat exchangers to the circulating water system through the cooling water heat exchangers. Major components for this subsystem are two 100 percent, motor-driven centrifugal pumps, and two 100 percent cooling water heat exchangers.

2.4.2.9 Compressed Air

The compressed air system comprises the instrument air and service air subsystems. The service air system supplies compressed air to the instrument air dryers and to hose connections for general plant use. The service air system will include one 100 percent capacity air motor-driven compressor, service air headers, distribution piping, and hose connections. Exhaust bleed air from the three CTGs will be the normal source of compressed air. The motor-driven compressor will provide compressed air when the plant is off-line. The instrument air system supplies dry compressed air at the required pressure and capacity for all control air demands, including pneumatic controls, transmitters, instruments, and valve operators. The instrument air system will include two 100 percent capacity air dryers with prefilters and after filters, an air receiver, instrument air headers, and distribution piping.

2.4.3 Fuel Availability

Fuel will be delivered by PG&E via a high-pressure interstate transmission line (Line 2, and Line 401) carrying natural gas from Canada (see Section 6.0, Natural Gas Supply). There is sufficient capacity through the interstate line to supply CVEC. It is conceivable that the connecting line to CVEC could become temporarily inoperable due to a breach in the line or from other causes, resulting in fuel not being available at CVEC.

2.4.4 Water Availability

Water for CVEC will be reclaimed water from the Fresno-Clovis WWTF. Domestic water will be provided by the City of San Joaquin. The availability of water to meet the needs of CVEC is discussed in more detail in Section 7.0, Water Supply.

2.4.5 Project Quality Control

The Quality Control Program that will be applied to CVEC is summarized in this section. The objective of the Quality Control Program is to ensure that all systems and components have the appropriate quality measures applied; whether it be during design, procurement, fabrication, construction, or operation. The goal of the Quality Control Program is to achieve the desired levels of safety, reliability, availability, operability, constructibility, and maintainability for the generation of electricity.

The required quality assurance for a system is obtained by applying controls to various activities, according to the activity being performed. For example, the appropriate controls for design work are checking and review, and the appropriate controls for manufacturing and construction are inspection and testing. Appropriate controls will be applied to each of the various activities for the project.

2.4.5.1 Project Stages

For quality assurance planning purposes, the project activities have been divided into the following nine stages that apply to specific periods of time during the project.

2.4.5.1.1 Conceptual Design Criteria

Activities such as definition of requirements and engineering analyses.

2.4.5.1.2 Detail Design

Activities such as the preparation of calculations, drawings, and lists needed to describe, illustrate, or define systems, structures, or components.

2.4.5.1.3 Procurement Specification Preparation

Activities necessary to compile and document the contractual, technical, and quality provisions for procurement specifications for plant systems, components, or services.

2.4.5.1.4 Manufacturer's Control and Surveillance

Activities necessary to ensure that the manufacturers conform to the provisions of the procurement specifications.

2.4.5.1.5 Manufacturer Data Review

Activities required to review manufacturers' drawings, data, instructions, procedures, plans, and other documents to ensure coordination of plant systems and components, and conformance to procurement specifications.

2.4.5.1.6 Receipt Inspection

Inspection and review of product at the time of delivery to the construction site.

2.4.5.1.7 Construction/Installation

Inspection and review of storage, installation, cleaning, and initial testing of systems or components at the facility.

2.4.5.1.8 System/Component Testing

Actual operation of generating facility components in a system in a controlled manner to ensure that the performance of systems and components conform to specified requirements.

2.4.5.1.9 Plant Operation

As the project progresses, the design, procurement, fabrication, erection, and checkout of each generating facility system will progress through the nine stages defined above.

2.4.5.2 Quality Control Records

The following quality control records will be maintained for review and reference:

- Project instructions manual
- Design calculations

- Project design manual
- Quality assurance audit reports
- Conformance to construction records drawings
- Procurement specifications (contract issue and change orders)
- Purchase orders and change orders
- Project correspondence

For procured component purchase orders, a list of qualified suppliers and subcontractors will be developed. Before contracts are awarded, the subcontractors' capabilities will be evaluated. The evaluation will consider suppliers' and subcontractors' personnel, production capability, past performance, and quality assurance program.

During construction, field activities are accomplished during the last four stages of the project: receipt inspection, construction/installation, system/component testing, and plant operations. The construction contractor will be contractually responsible for performing the work in accordance with the quality requirements specified by contract.

The subcontractors' quality compliance will be surveyed through inspections, audits, and administration of independent testing contracts.

A plant operation and maintenance program, typical of a project this size, will be implemented by CVEC to control operation and maintenance quality. A specific program for this project will be defined and implemented during initial plant startup.

2.5 Laws, Ordinances, Regulations, and Standards

The applicable LORS for each engineering discipline are included as part of the Engineering Appendices 10A through 10G. A summary of all LORS is provided in Appendix 1D.

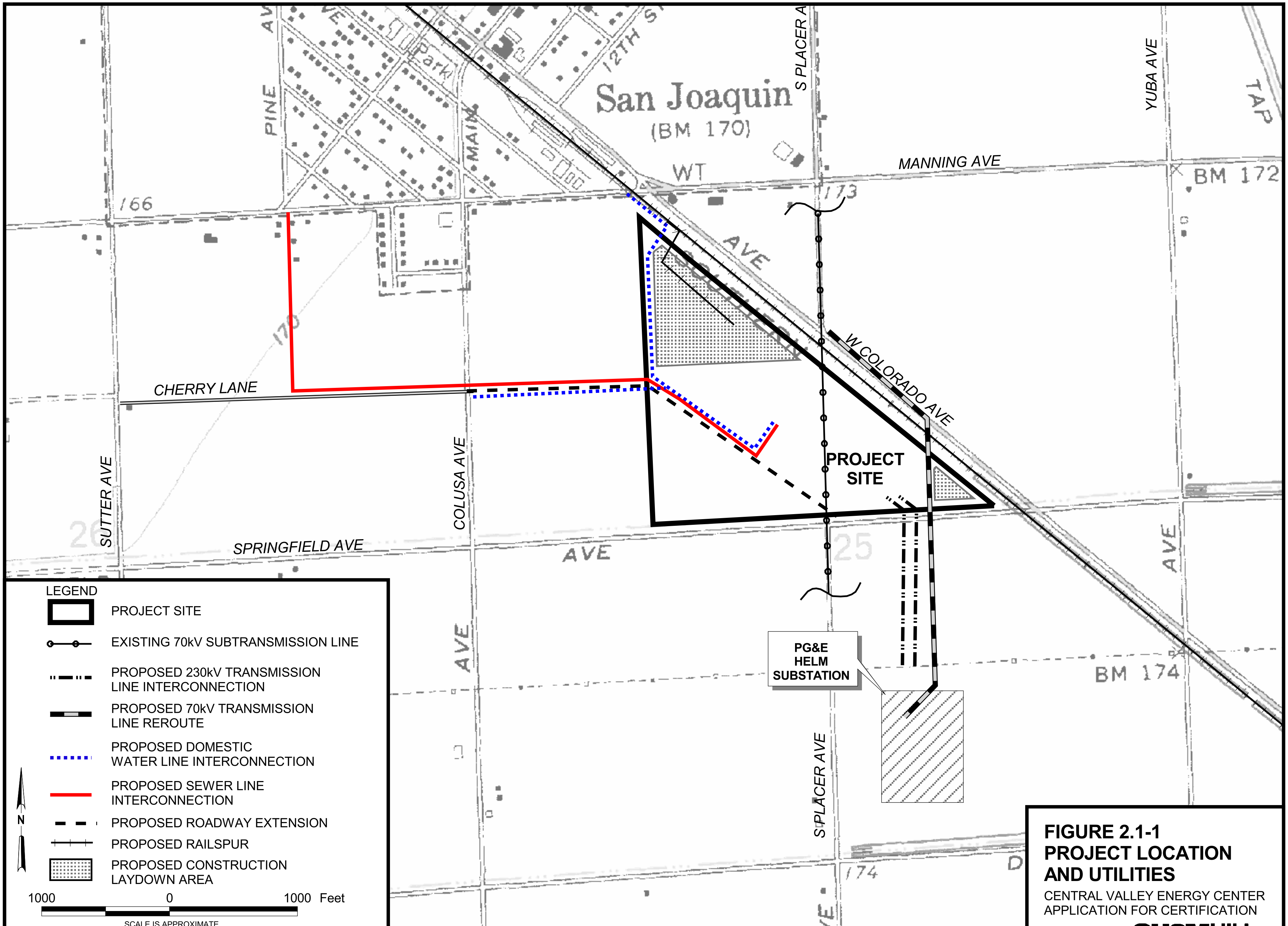

FIGURE 2.1-1
PROJECT LOCATION AND UTILITIES

CENTRAL VALLEY ENERGY CENTER
APPLICATION FOR CERTIFICATION

CH2MHILL

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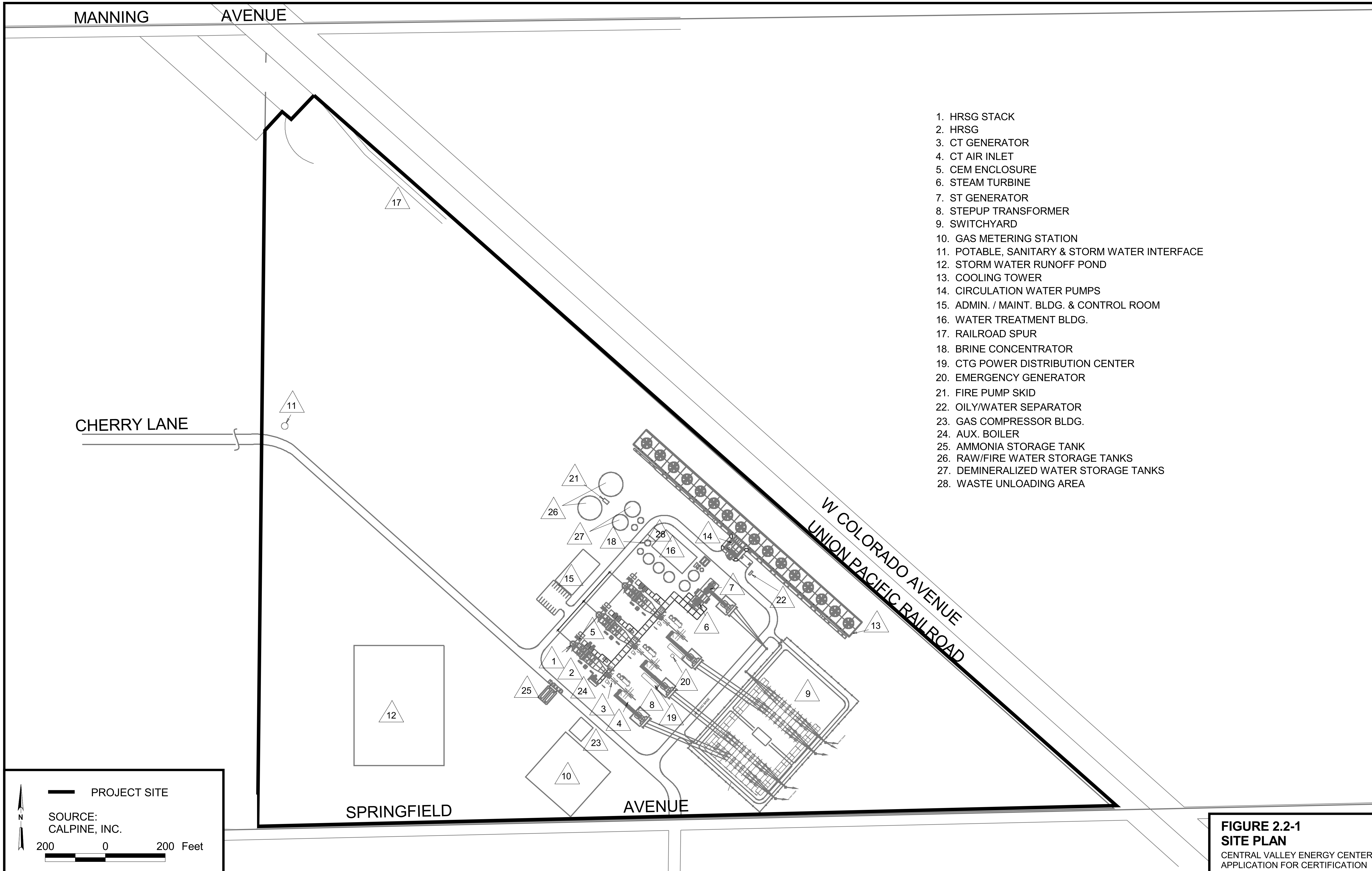
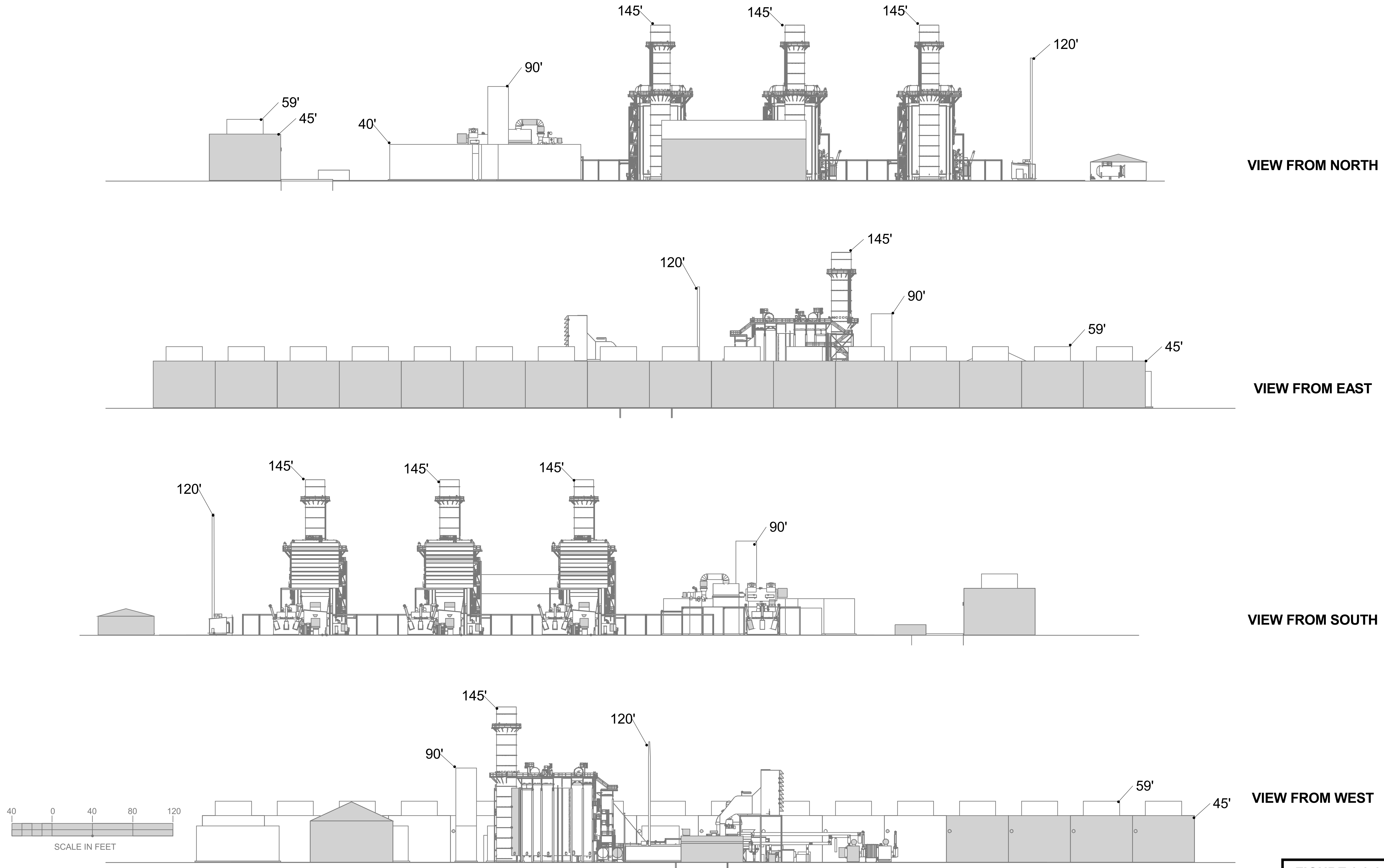


FIGURE 2.2-1
SITE PLAN
CENTRAL VALLEY ENERGY CENTER
APPLICATION FOR CERTIFICATION

CH2MHILL



SOURCE: PARSONS, 2001
cvecelev.dgn

FIGURE 2.2-2
PLANT ELEVATIONS
CENTRAL VALLEY ENERGY CENTER
APPLICATION FOR CERTIFICATION
CH2MHILL

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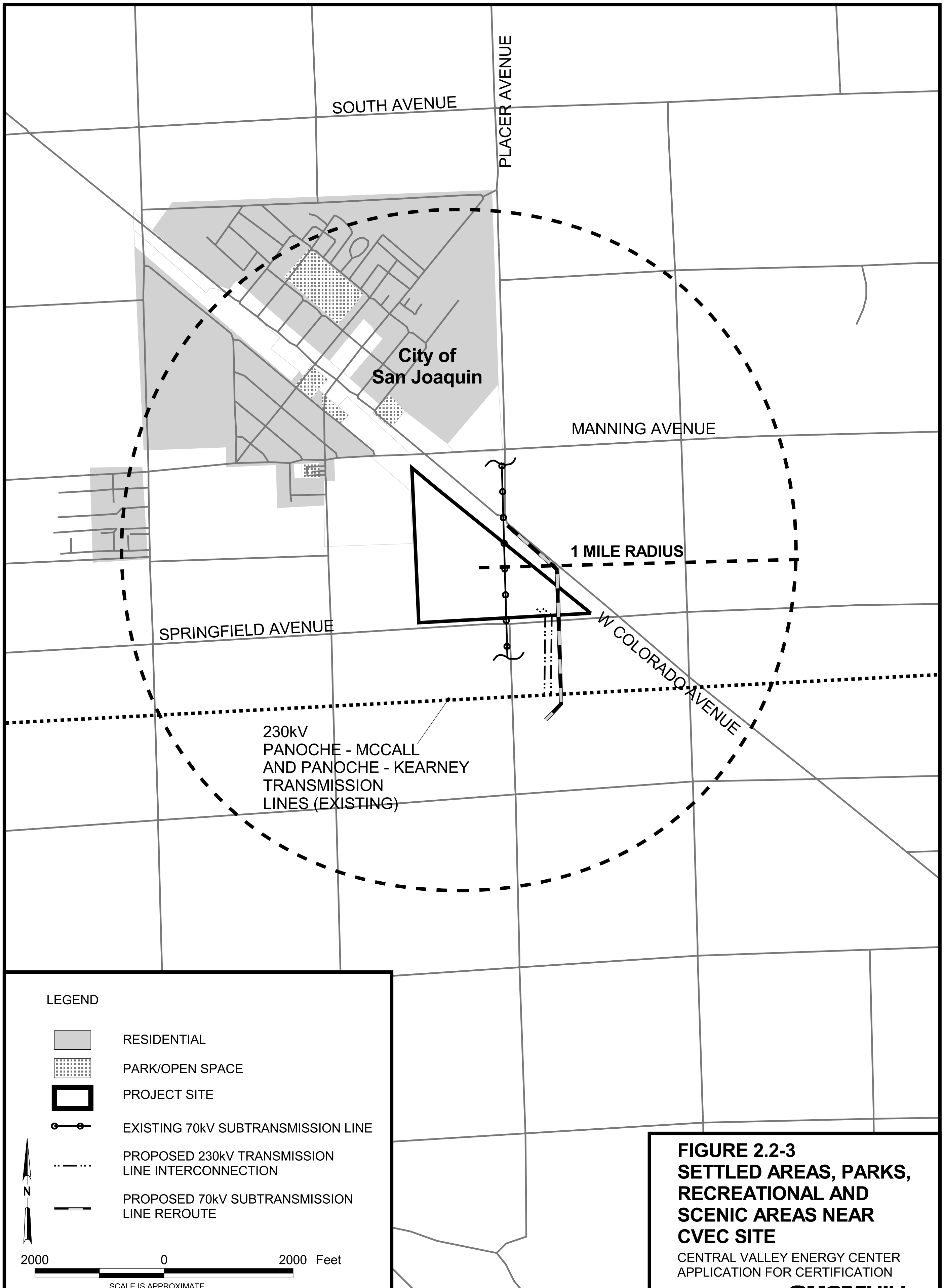

FIGURE 2.2-3
SETTLED AREAS, PARKS, RECREATIONAL AND SCENIC AREAS NEAR CVEC SITE

CENTRAL VALLEY ENERGY CENTER
APPLICATION FOR CERTIFICATION

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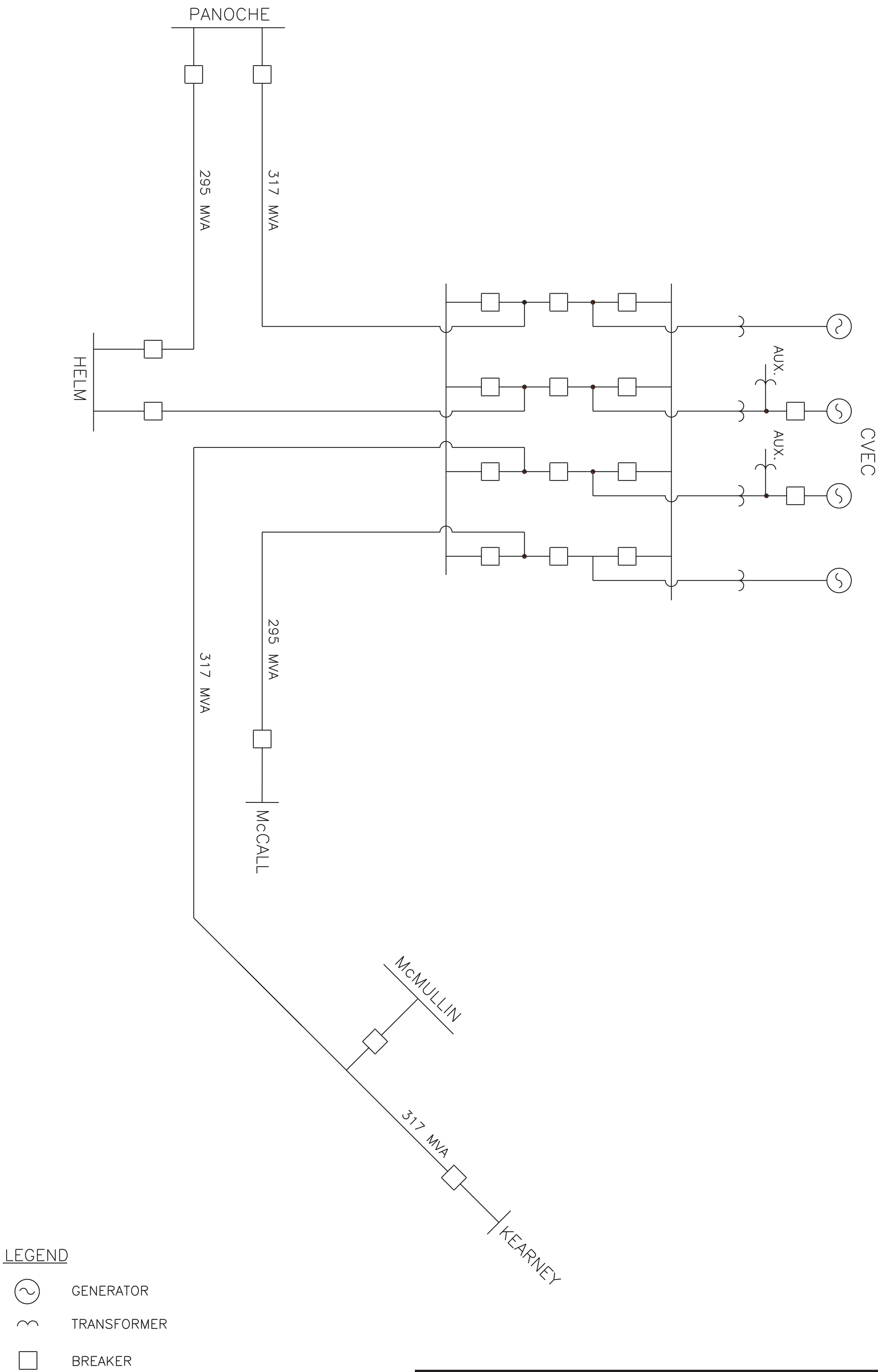

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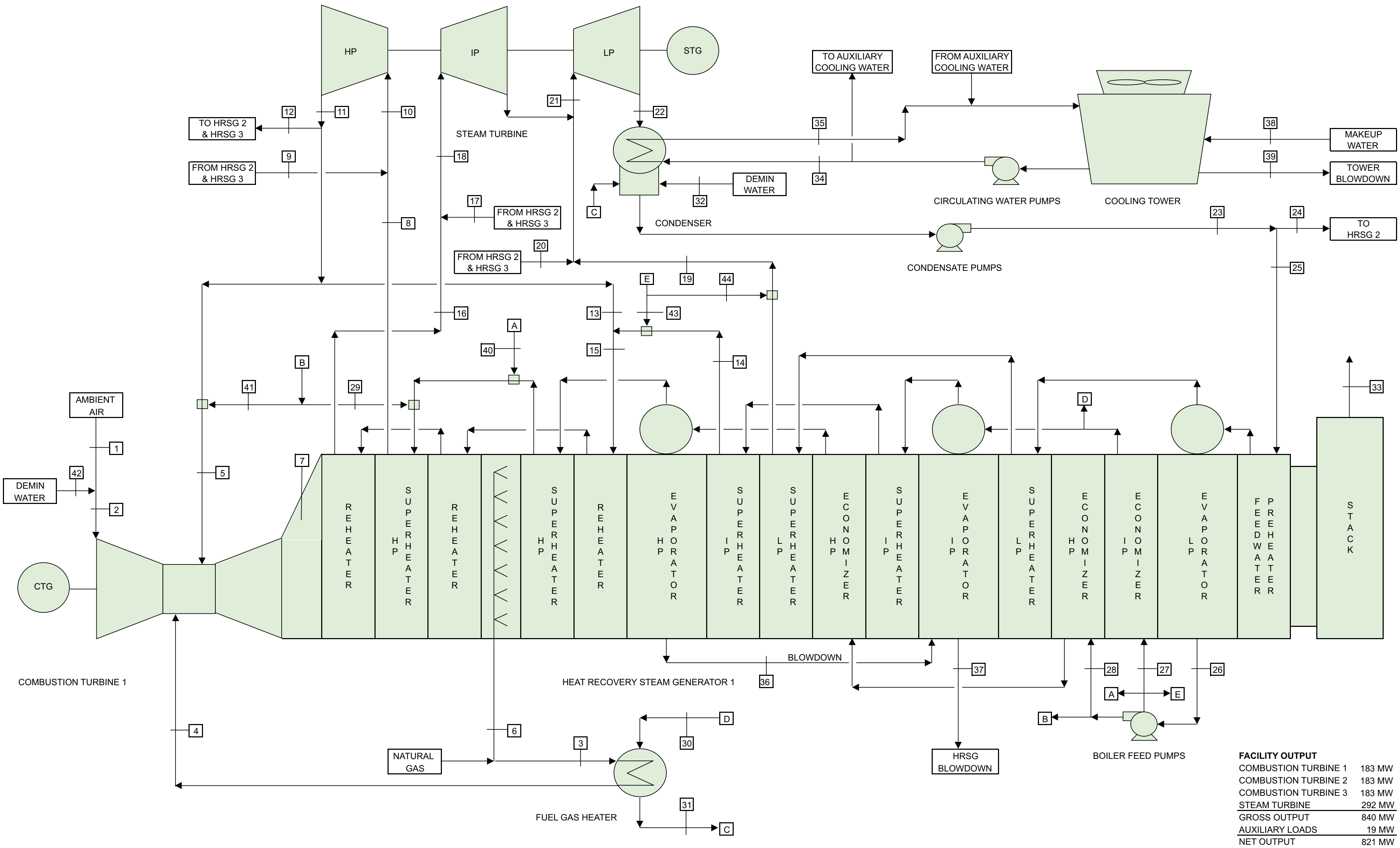
FIGURE 2.2-4
ONE-LINE SCHEMATIC OF THE PROPOSED CVEC 230 kV INTERCONNECTION
CENTRAL VALLEY ENERGY CENTER APPLICATION FOR CERTIFICATION
CH2MHILL



FACILITY OUTPUT

COMBUSTION TURBINE 1	183 MW
COMBUSTION TURBINE 2	183 MW
COMBUSTION TURBINE 3	183 MW
STEAM TURBINE	292 MW
GROSS OUTPUT	840 MW
AUXILIARY LOADS	19 MW
NET OUTPUT	821 MW

Design Case:	**Average Day**		
Configuration:	3X1, HPD	Site Altitude	180 ft
Dry Bulb Temperature:	61 degrees F	Wet Bulb Temperature:	53 degrees F
Fog:	Yes		
Power Augmentation:	No		
Duct Firing:	No		
Source: CALPINE			

3402_34 (10/23/01)

FIGURE 2.2-5a
HEAT AND MASS BALANCE DIAGRAM
CENTRAL VALLEY ENERGY CENTER APPLICATION FOR CERTIFICATION

CH2MHILL

Stream No.	Units	1	2	3	4	5	6	7	8
Mass Flow	lb/hr	3,551,286	3,556,157	81,526	81,526	0	0	3,634,605	427,718
Temperature	^oF	61	55	60	330	n/a	n/a	1,103	1,043
Pressure	psia	14.61	14.46	425	415	n/a	n/a	15.19	1,239
Stream No.	**Units**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**
Mass Flow	lb/hr	855,437	1,283,155	1,253,787	835,858	417,929	54,146	472,074	472,074
Temperature	^oF	1,043	1,043	677	677	677	564	665	1,049
Pressure	psia	1,239	1,239	304	304	304	294	294	260
Stream No.	**Units**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Mass Flow	lb/hr	944,149	1,416,223	77,133	154,265	1,670,270	1,670,270	1,231,038	820,692
Temperature	^oF	1,049	1,049	575	575	660	85	88	88
Pressure	psia	260	260	73	73	61	1.20	120	120
Stream No.	**Units**	**25**	**26**	**27**	**28**	**29**	**30**	**31**	**32**
Mass Flow	lb/hr	410,346	#VALUE!	95,254	427,718	0	41,109	41,109	0
Temperature	^oF	88	321	292	321	n/a	462	166	n/a
Pressure	psia	120	91	435	1,360	n/a	311	301	n/a
Stream No.	**Units**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**
Mass Flow	lb/hr	3,634,605	106,039,067	106,039,067	0	0	1,622,477	324,041	0
Temperature	^oF	193	68	84	n/a	n/a	70	84	n/a
Pressure	psia	14.61	35	25	n/a	n/a	20	25	n/a
Stream No.	**Units**	**41**	**42**	**43**	**44**				
Mass Flow	lb/hr		4,871	0	20				
Temperature	^oF	n/a	70	n/a	321				
Pressure	psia	n/a	14.46	n/a	91				

Source: CALPINE

3402_30 (10/17/01)

FIGURE 2.2-5b
HEAT AND MASS BALANCE DATA
DESIGN CASE: AVERAGE DAY
CENTRAL VALLEY ENERGY CENTER APPLICATION FOR CERTIFICATION

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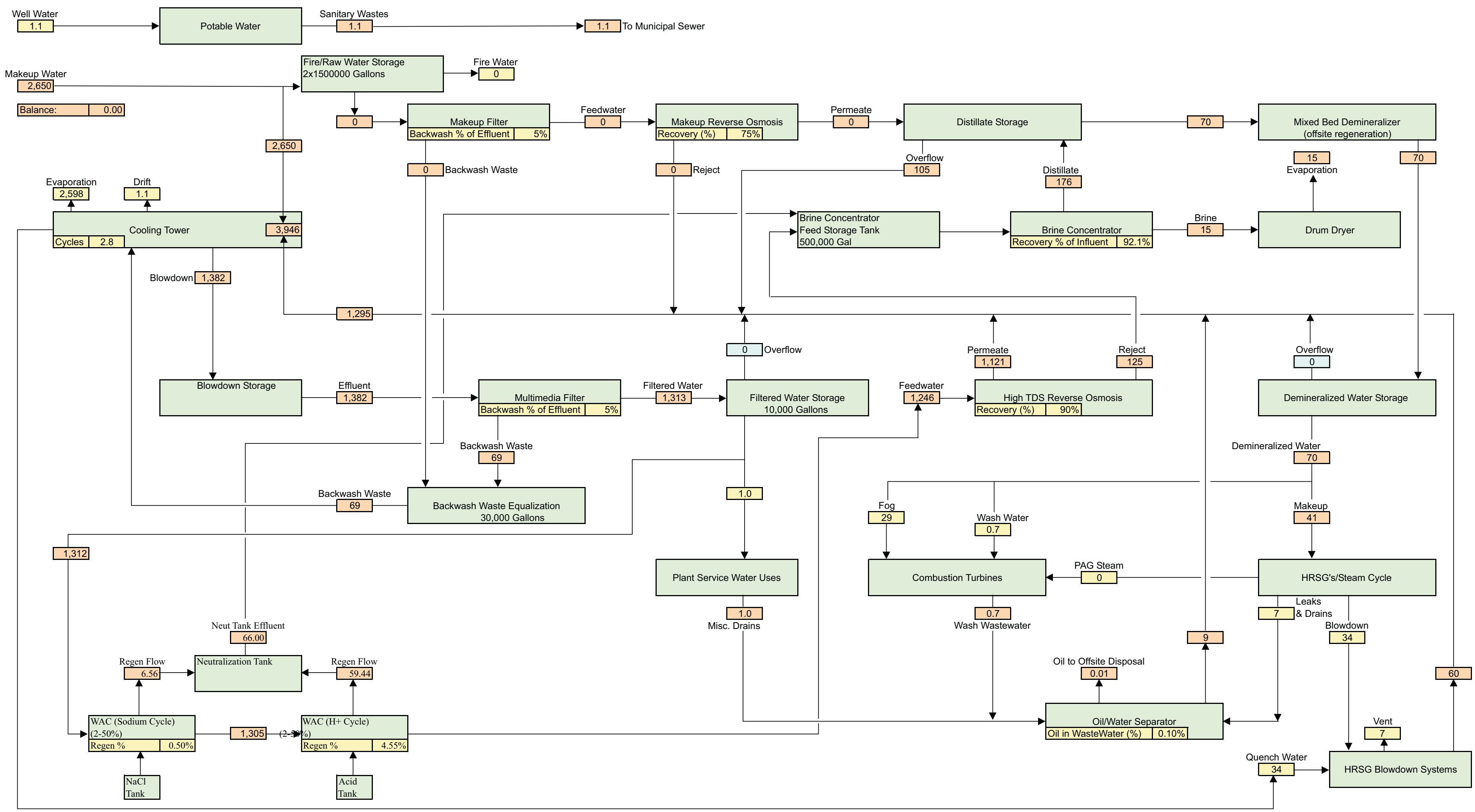


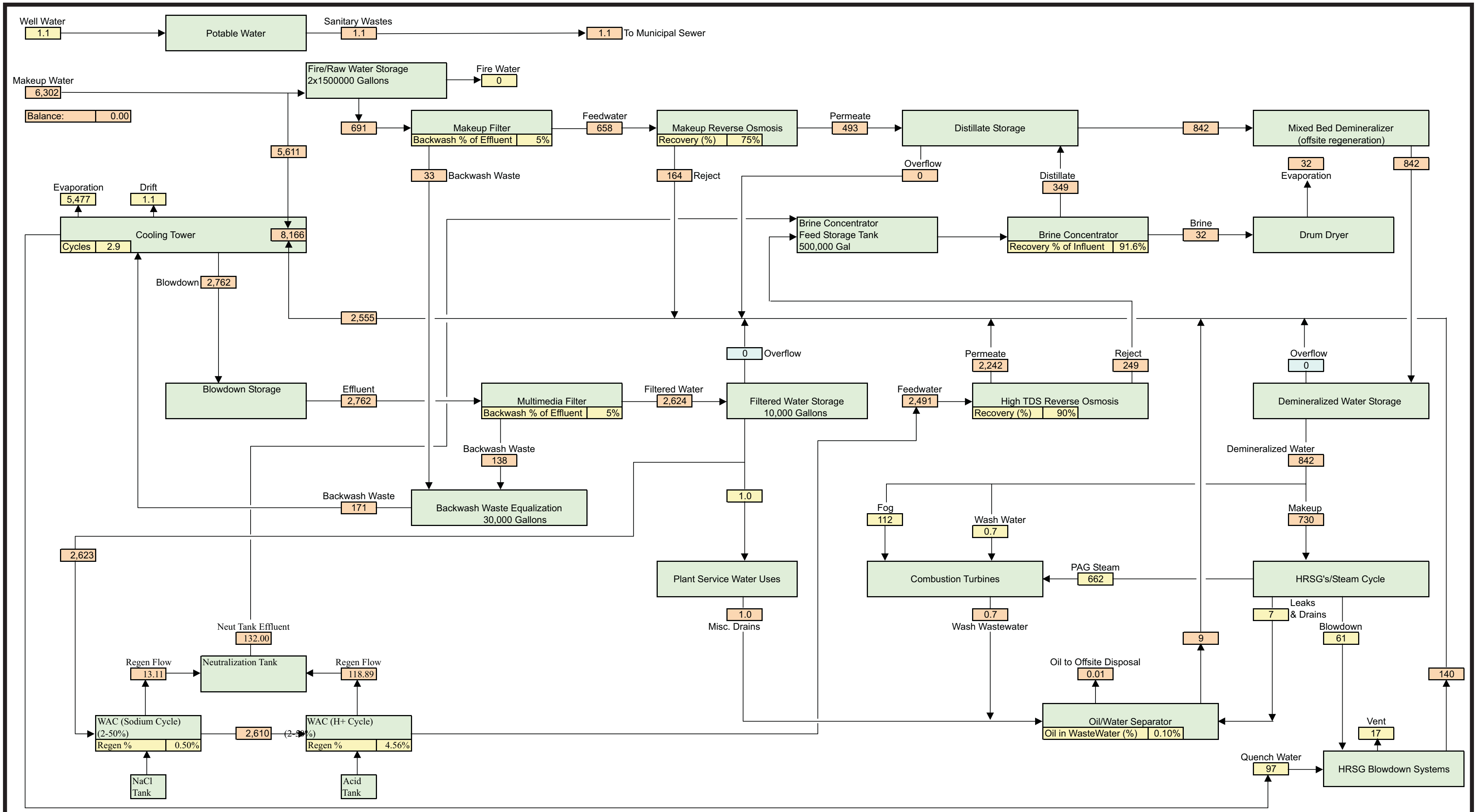
Design Case:	**Case L**		
	Annual Average		
Configuration:	3X1 HPD	Ambient Pressure	14.61 psia
Dry Bulb Temperature:	61.00 degrees F	Wet Bulb Temperature:	52.96 degrees F
Fog:	Yes		
Power Augmentation:	No		
Duct Firing:	No		

Source: CALPINE

3402_16 (10/8/01)

FIGURE 2.2-6a
ANNUAL AVERAGE WATER BALANCE DIAGRAM
CENTRAL VALLEY ENERGY CENTER APPLICATION FOR CERTIFICATION

CH2MHILL



Design Case:	**Case D**		
	Typical Summer High		
Configuration:	3X1 HPD	Ambient Pressure	14.61 psia
Dry Bulb Temperature:	100.00 degrees F	Wet Bulb Temperature:	72.00 degrees F
Fog:	Yes		
Power Augmentation:	Yes		
Duct Firing:	Yes		
Source: CALPINE			

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FIGURE 2.2-6b
TYPICAL SUMMER HIGH WATER BALANCE DIAGRAM
CENTRAL VALLEY ENERGY CENTER APPLICATION FOR CERTIFICATION

CH2MHILL